BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

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In The Matter Of PUBLIC UTILITIES COMMISSION. Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs	DOCKET NO. 2008-0273

REPLY BRIEF OF THE HECO COMPANIES AND CONSUMER ADVOCATE

AND CERTIFICATE OF SERVICE

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TABLE OF CONTENTS

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REPLY BRIEF OF THE HECO COMPANIES AND CONSUMER ADVOCATE

Pursuant to the Commission's April 27, 2009 Order[1] in the above-captioned proceeding, Hawaiian Electric Company, Inc. ("HECO") and its subsidiaries Maui Electric Company, Limited ("MECO") and Hawaii Electric Light Company, Inc. ("HELCO")(collectively, the "HECO Companies") and the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs ("Consumer Advocate")(collectively, the "Joint Parties"), herein respectfully submit their Reply Brief in the above-captioned proceeding. The Joint Parties' Opening Brief, filed June 12, 2009, generally addresses the contentions included in the other parties' Opening Briefs. Therefore, this Reply Brief will not attempt to be all-inclusive, and will instead focus on those contentions that may warrant further response.[2]

I. INTRODUCTION

[1] Order Granting The County Of Hawaii's Motion For Approval To Amend Its Status As An Intervenor To A Participant, Filed On April 8, 2009; Granting The City And County Of Honolulu's Motion For Approval To Amend Its Status As An Intervenor To A Participant, Filed On April 8, 2009; Amending Hawaii Holdings, LLC, Doing Business As First Wind Hawaii And Sempra Generation's Status As Intervenors To Participants; And Amending The Schedule In This Proceeding. This Order was modified by the Commission's May 21, 2009 letter granting a request by DBEDT to extend the deadline for the filing of Reply Briefs until June 26, 2009.

[2] The Joint Responses to Legal Questions Regarding Feed-In Tariffs of the HECO Companies and Consumer Advocate ("Joint Responses"), filed June 12, 2009, generally address the responses in the other parties' Opening Briefs to Sections VI through IX of the legal questions that were posed in this docket and distributed by the Commission on May 8, 2009. Therefore, the Hawaiian Electric Companies and Consumer Advocate will not be filing a reply brief with respect to Sections VI through IX of the legal questions.

The Opening Briefs filed on June 12, 2009 in this proceeding reveal that a number of the parties are in partial or general agreement on many of the significant issues. This includes but is not limited to general agreement that:

1. The State should move decisively and irreversibly away from imported fossil fuel for electricity with an appropriately designed FIT as one complementary method of accelerating the acquisition of renewable energy for the State;[3]

2. Preservation of system security, power quality and avoidance of undue ratepayer impacts are also considerations in establishing a FIT for Hawaii;[4]

3. A Hawaii FIT should integrate appropriately with the State's and utilities' other renewable energy procurement programs;[5]

4. There should be an initial FIT ("Initial FIT") which should be followed by regular updates through which modifications to the Initial FIT may be considered;[6]

5. The Initial FIT should focus on the technologies with which the HECO Companies have some commercial experience and which can more efficiently be accommodated through a FIT program. Other technologies should be evaluated through the FIT update ("FIT Update") process;[7]

6. It is appropriate to have some limit upon the size of projects eligible for the Initial FIT;[8]

7. It is appropriate to have interconnection rules and procedures to assure system reliability and security;[9]

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3 See DBEDT Opening Brief at page 19-20, HREA Opening Brief at page 3, SA/HSEA Opening Brief at page 2, Sopogy Opening Brief at page 3, Blue Planet Opening Brief at page 1, and Clean Energy Maui ("CEM") Opening Brief at page 1.

4 See HREA Opening Brief at pages 3 and 12, Sopogy Opening Brief at pages 4-5, Haiku Design and Analysis ("HDA") Opening Brief at pages 6 and 12, and CEM Opening Brief at pages 2-3, and 8.

5 See DBEDT Opening Brief at page 23, HREA Opening Brief at pages 6-7, SA/HSEA Opening Brief at page 4, HDA Opening Brief at Page 4, and CEM Opening Brief at pages 27-28.

6 See DBEDT Opening Brief at page 71, HREA Opening Brief at pages 12-13, Sopogy Opening Brief at page 4, HDA Opening Brief at Page 7,

7 See DBEDT Opening Brief at page 51, HREA Opening Brief at page 14, SA/HSEA Opening Brief at page 7, Sopogy Opening Brief at page 4, and HDA Opening Brief at Page 4.

8 See DBEDT Opening Brief at page 54, HREA Opening Brief at pages 12-13, SA/HSEA Opening Brief at page 8, Sopogy Opening Brief at page 5, and HDA Opening Brief at Page 4.

9 See DBEDT Opening Brief at pages 79-80, HREA Opening Brief at pages 12, Sopogy Opening Brief at page 12, HDA Opening Brief at page 4, Blue Planet Opening Brief at page 4 of Exhibit A, CEM Opening Brief at page 14, and Zero Emissions Opening Brief at page 26.

8. Rates paid to project developers should be just and reasonable;[10]

9. It is appropriate to have some form of annual limit, differentiated by island, on the amount of renewable energy that will be integrated through a FIT;[11]

10. FIT rates should be based upon Hawaii project-specific cost information to the extent possible. To the extent that Hawaii specific information is not available, secondary data sources may be used to the extent that data is appropriately adjusted so as to be relevant for Hawaii price development;[12]

11. It is appropriate to impose reasonable operational standards and requirements, including generation curtailment, in order to maintain system reliability;[13]

12. Once an appropriately designed FIT rate is in place and the resource is operating and delivering power at that rate and pursuant to its FIT Agreement, that rate should not be subject to adjustment mid-course;[14]

13. The standard term for a Schedule FIT Agreement should be 20 years for all eligible renewable resources;[15]

14. The appropriate vehicle to document the terms, conditions and obligations between the developer of the renewable resource and the utility is a standard offer contract;[16] and

15. Consistent with the Energy Agreement, any FIT program must insure that the electric utility implementing the program remains financially sound.[17]

Where the parties disagree, to the extent they do, it is with regard to the pace and scope of

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10 See DBEDT Opening Brief at page59, HREA Opening Brief at page 19, and Sopogy Opening Brief at page 10.

11 See DBEDT Opening Brief at page 88, HREA Opening Brief at page 25, SA/HSEA Opening Brief at page 20, and Sopogy Opening Brief at page 9.

12 See DBEDT Opening Brief at page 61, HREA Opening Brief at page 16, SA/HSEA Opening Brief at 11, and Sopogy Opening Brief at page 4.

13 See HREA Opening Brief at pages 23-24, Sopogy Opening Brief at page 12 and HDA Opening Brief at Page 8.

14 See Blue Planet Opening Brief at page 11, Clean Energy Maui Opening Brief at 25, and Zero Emissions Opening Brief at page 37.

15 See DBEDT Opening Brief at page 65, HREA Opening Brief at page 21, SA/HSEA Opening Brief at page 3, Sopogy Opening Brief at page 11, Blue Planet Opening Brief at page 33, CEM Opening Brief at page 25, and Zero Emissions Opening Brief at page 37.

16 See DBEDT Opening Brief at page 70, HREA Opening Brief at page 21, SA/HSEA Opening Brief at page 3, Sopogy Opening Brief at page 11, and HDA Opening Brief at Page 11.

17 See DBEDT Opening Brief at page 76, HREA Opening Brief at page 22, Sopogy Opening Brief at page 11, and HDA Opening Brief at page 30.

the Initial FIT. As expressed during the technical and settlement meetings held between the parties, the Joint Parties acknowledge and understand both the commercial goals of the parties who seek to secure another vehicle pursuant to which commercial projects may be developed or facilitated, and the altruistic goals of those parties which seek to move the State away from its dependence on fossil fuels immediately. It is the quest to reach these goals quickly that drives proposals such as Sopogy's proposal to set the target goal for the Initial FIT for the HECO Companies at 470 MW (Sopogy Opening Brief at 3), and Blue Planet Foundations's position that the Commission should not place any limits on project sizes so as to "encourage the maximum amount of renewable energy generation in the shortest time period." (Blue Planet Opening Brief at 21

In formulating their joint FIT proposal submitted to the Commission on December 23, 2008 ("Proposed FIT") as well as the positions set forth in their joint final statement of position ("Joint FSOP" filed March 30, 2009), the HECO Companies and Consumer Advocate are required to consider factors, imposed by Commission order, statute and regulation, that none of the other parties to this proceeding are subject to. In particular, the HECO Companies are required by the Commission's General Order No. 7 ("Standards for Electric Utility Service in the State of Hawaii") to provide safe and reliable service to their customers and maintain levels of power quality established by the Commission. The Consumer Advocate is charged with protecting and advancing the interests of Hawaii's consumers of regulated public utility service. (See, generally, Hawaii Revised Statutes Section 269-51) Accordingly, the Joint Parties do not have the same discretion that the intervenors do to pursue policies or positions which may be contrary to the letter and intent of these obligations. In practical terms, the Joint Parties are not able to simply propose an expansive FIT program and then wait and see what the impacts of that proposal might be. Similarly, the Joint Parties are not in a position where they can agree to deal with system-wide outages, harm to customer equipment or dramatically increased customer rates after the fact. Rather, the Joint Parties must design their FIT proposal so that to the greatest degree possible potential impacts are understood and unintended consequences, to the extent they occur, can be either prevented or mitigated. This requires that the Joint Parties focus not only on a best design for a FIT, but also how this design is appropriately balanced against the HECO Companies' other renewable energy procurement mechanisms and obligations. Once additional information is obtained, from observation of the Initial FIT program, ongoing system studies, and the HECO Companies' other renewable energy procurement programs, then the Initial FIT can be appropriately modified through the FIT Update process. This reasonable and responsible course helps assure that unintended consequences from the Initial FIT are minimized and manageable and that the HECO Companies are not over-committing to obligations the impact of which may not be fully realized or even understood until well after the FIT program is past its infancy.

In evaluating a best design for a FIT, it is important to keep in mind the guidance provided by the Energy Agreement.[18] The Energy Agreement recognized that feed-in tariffs are beneficial for the development of renewable energy, because they "provide predictability and certainty with respect to the future prices to be paid for renewable energy and how much of such energy the utility will acquire." (Energy Agreement at 16)(emphasis supplied) In discussing the best design for feed-in tariffs that support the Hawaii Clean Energy Initiative, the Energy Agreement specifically referenced such factors as "size or locational limits for projects qualifying

[18] On October 20, 2008, the Governor of the State of Hawaii, the State Department of Business Economic Development and Tourism (DBEDT), the Consumer Advocate and the HECO Companies entered into a comprehensive agreement ("Energy Agreement") designed to move the State away from its dependence on imported fossil fuels for electricity and ground transportation, and toward "indigenously produced renewable energy and an ethic of energy efficiency.

for the feed-in tariff," "what annual limits should apply to the amount of renewables allowed to take the feed-in tariff terms," and the "continuing role of the Competitive Bidding Framework." (Energy Agreement at 17) Accordingly, appropriate limits on the FIT program and the continuation of the Competitive Bidding Framework were contemplated by and foreseen by the State, Consumer Advocate and HECO Companies as a means to insure that any adopted FIT program avoids unintended consequences to the greatest degree possible and that the utilities' ability to serve its customers pursuant to just and reasonable rates is not threatened.

In summary, the parties are in agreement on a number of general principles as discussed above. It is certainly possible that with more information, study, and the build out of the infrastructure necessary to assist with the integration of higher levels of variable renewable resources, the parties may be able to reach agreement on many of the issues and achieve the levels of renewable energy penetration envisioned by at least some of the intervenors. At this time, however, the Joint Parties must deal with the facts as they exist with regard to the ability of the existing systems, given existing types and levels of generation and infrastructure, to accommodate additional variable generation, the state of technology and the analytical tools which may be able to assist in integrating additional renewables over time and the availability and cost of that technology. As explained above, the Joint Parties are not in a position to agree to the intervenor proposals to have a FIT that is open on day one to all renewable resources of any size or type to secure a must- take, take-or-pay, 20-year term contract (plus right to extension) which guarantees recovery of developer costs (including all interconnection costs) plus a to-be-determined level of profit and simply hope that there are no reliability or cost concerns. The Joint Parties are not permitted to simply assume or speculate that there will not be system outages or harm to customer equipment. The Joint Parties are instead constrained by existing rules to achieve the State mandated goals for system reliability and cost effectiveness, simultaneously with implementation of a FIT program. With these considerations in mind, the Proposed FIT presents for Commission approval the appropriate balance of a process to streamline the addition of new, renewable distributed generation to the system, while also providing assurance that the initial phase of the program will not cause adverse system or ratepayer impacts.

II. DISCUSSION

Many of the intervenor parties' positions articulated through their Opening Briefs are either identical or very similar in many circumstances. In the interest of brevity, this Reply Brief will respond generally to the common issues raised but does not respond individually to each party's assertions or allegations in each party's Opening Brief.

A. The Commission Should Defer Making A Final Decision On Termination Or Extension Of The NEM Program Until The First FIT Update When Further Information Is Available With The NEM And FIT Programs Running Simultaneously.

As the Solar Alliance and Hawaii Solar Energy Association ("SA/HSEA") acknowledge in their Opening Brief, the Energy Agreement provides that "... NEM will be replaced with an appropriate feed-in-tariff...." (SA/HSEA Opening Brief at footnote 6) SA/HSEA also acknowledge the Joint Parties' proposal in their Joint FSOP, in part in response to concerns raised by the intervenors, that the NEM program be allowed to continue in its current format until the first FIT Update is completed. (Id.)

Nevertheless, SA/HSEA takes the position that the NEM program should "continue indefinitely." (Id.) SA/HSEA describes the NEM program as addressing the need of many home-owning and business-owning ratepayers to "manage their operating costs." (SA/HSEA Opening Brief at 4) SA/HSEA describes the FIT program as a "mechanism for deriving income from the production of energy." (Id.) SA/HSEA together with Sopogy , DBEDT and the Hawaii Renewable Energy Alliance ("HREA") seek to blend these two programs by allowing NEM customers to oversize their systems for the specific purpose of selling excess energy to the utility at FIT rates. (SA/HSEA Opening Brief at 6; Sopogy Opening Brief at 8; DBEDT Opening Brief at 31; HREA Opening Brief at 2) None of the parties provide any evidence regarding the potential impacts to the system or upon the utilities' ability to administer these programs under a scenario where NEM customers are also allowed to be market participants. The intervenors also neglect to provide any analysis of the cost implications associated with allowing customers whose original intent in installing their distributed generation systems was to reduce their energy bills could evolve to now seek profit from the sale of energy to the utility.

As discussed above, the Joint Parties agree that the NEM program should be continued in its current state until the first FIT Update which is anticipated to be in place approximately two years from the Commission's order adopting the Initial FIT.[19] During this time period the Commission and parties can collect and analyze information regarding how the two programs operate in parallel and whether there is any basis to continue the NEM program, in whole or in part, or to allow NEM customers to participate in both the NEM and FIT programs simultaneously. Moreover, this additional time will allow the parties to fully evaluate the issue of the contribution to the utility's fixed costs which is avoided in part by NEM customers and whether these costs are offset in whole or in part by the benefits which the NEM program provides. Accordingly, the Joint Parties respectfully request that the Commission defer any decision on extension or modification of the NEM program, which decision will ultimately have to be effectuated in the NEM docket, until the first FIT Update.

B. All Resources Have The Potential To Adversely Affect System Security And Power Quality Depending Upon The Technology, Size, Operational Characteristics, Location And Type Of Grid That The Resource Is Being Integrated Into.

As noted above, SA/HSEA now supports the Joint Parties' proposal that the FIT initially be eligible only for the following technologies: Solar PV (also referred to as just "PV"), CSP, Wind and In-Line Hydro (SA/HSEA Opening Brief at 7). SA/HSEA note that their support is in part a response to evidence from the panel hearing in this docket suggesting that "these are the only technologies that are "shovel ready" at this time." (Id.) SA/HSEA goes on to state that due to the impacts which PV can have on a utility system grid, PV generators "will not have a negative impact on the HECO Companies' reliability and/or power quality." (Id.)

The Joint Parties do not dispute the fact that solar PV, due to the fact that its production of energy can in many circumstances be coincident with periods of higher demand, can have less negative impacts upon system reliability and power quality than other variable resources. However, it must be noted that just as other variable resources can have negative impacts upon system reliability and power quality, so can PV or any resource depending upon the specific circumstances of the resource and the grid that it is seeking to integrate to. Connecting any variable generation source to a system has the potential for a negative impact. For example, large PV systems or a large aggregate of PV on a system can displace conventional generation which could otherwise be utilized to respond to changes in the system. Also, the fluctuation of power output from any intermittent generation source, including a PV facility (e.g., due to passing

[19] Haiku Design and Analysis ("HDA") is largely in support of this approach. See, HDA Opening Brief at 16

clouds), can have a negative impact on reliability and power quality. This is because a standard PV system, like most intermittent generation sources, does not have any of the characteristics of conventional generation that an electric grid requires (e.g., load following, droop response, inertial response, quick load pickup, and voltage regulation).

As already stated, the Joint Parties contend that the potential impact of any generation source depends on many different factors. One of those factors also includes the system or electric grid to which the proposed generation source seeks to connect. For a larger grid, the addition of an intermittent source of energy might have a potentially negative impact, but that impact may be immaterial depending on the grid and the unit. However, on a smaller grid, the impact of that addition may not be immaterial. The electric systems on each island are definitely smaller relative to most systems, but even just within Hawaii, the relative size differences among the island systems do not allow a "one size fits all" approach.

This simply highlights the fact that it is difficult to make generalized statements regarding any particular resource or that resource's impact upon the utility grid. To a large extent, one cannot know what that impact, positive or negative, will be until the resource type, size, operating characteristics, and location of that resource is known and evaluated. This again presents the issue of why it is difficult to provide a specific number or numbers as to the amount of a particular type of resource a particular grid can accept. The most correct response to this question is not to guess at a particular number, but rather to conduct the appropriate evaluations necessary to determine what those amounts could be given reasonable assumptions that can be made . As discussed herein and in the Joint Parties' Opening Brief, this is the process that the HECO Companies are presently engaged in. Focusing on PV in particular, depending on the amount and type of distributed generation that is connected to a grid, and the operational ability of that grid to integrate the PV resource, PV resources can have negative impacts on system reliability and power quality. This is why it is reasonable to have initial system level and circuit penetration limits for certain types of generation such as PV.

C. System Security And Power Quality Cannot Be Assured At The Project Size Limits Proposed By The Intervenors.

SA/HSEA propose that the project size limit for the initial FIT be increased from those set forth in the Joint Parties' Proposed FIT to include projects of up to 5 MW for Oahu and 2.75 MW for HELCO and MECO. (SA/HSEA Opening Brief at 8) Project sizes of 2.75 MW on Maui would equate to 50% of some of MECO's largest circuits and represents approximately 1.5% of the peak generation and nearly 2% of the generation during typical daytime loads on both the MECO and HELCO systems. As such, generation of this size has a significant impact on these systems as a whole, especially if it is non-dispatchable and therefore, would require modifications to the utilities' online regulating reserve. At this proposed size, HELCO would require monitoring and control capabilities in order to be able to insure grid stability and power quality.

Sopogy proposes initial project size limits of 5 MW for Oahu, 3 MW for Maui, 3MW for the Big Island and 1 MW each for Molokai and Lanai.[20] (Sopogy Opening Brief at 5) Sopogy also proposes that these limits double every two years until, for example, the project size limit for Oahu reaches 20 MW in the next four years. Sopogy makes this proposal without any evidence that these island systems can integrate projects of the sizes proposed. Sopogy's proposal to arbitrarily impose limits that double every two years without any determination that such project

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[20] HREA supports the same project sizes for Oahu, Maui and the Big Island. (HREA Opening Brief at 12)

sizes can be accommodated without harm to system security and power quality is irresponsible and should not be adopted by the Commission.

Moreover, part of the reason why the Joint Parties' Proposed FIT elected the project size limits that it did was to allow for a diversity of both projects and developers. Increased project sizes to the levels advocated by SA/HSEA and Sopogy, would allow for only a limited number of projects and in some cases only a single project. For example, a 1 MW project on Lanai or Molokai would immediately meet the 15% penetration limit for those islands (advocated by SA/HSEA and Sopogy) (SA/HSEA Opening Brief at 20, Sopogy Opening Brief at 3) and exclude any other renewable energy projects.

DBEDT also proposes initial project sizes of 5 MW for Oahu and up to 3 MW for the HELCO and MECO systems. (DBEDT Opening Brief at 54-57) As discussed above, projects of this size will in many circumstances, particularly on the HECO Companies' neighbor island systems raise issues regarding the need for appropriate study of the resource's impact on the system, the need for additional regulating reserves, and the need for appropriate controls upon the resource. With regard to the Oahu system, project sizes in the range of 5 MW may be possible as discussed in more detail below. However, absent a thorough evaluation of these issues and appropriate actions to address any concerns, the utility will not be able to assure system reliability and security. DBEDT sets forth an extensive discussion of its rationale in support of its proposed project sizes. This discussion bears evaluation by the Commission as there are certain misperceptions contained within the discussion which when corrected, may have an impact upon the viability of the overall DBEDT proposal.

With regard to item (a) on page 54 of DBEDT's Opening Brief, DBEDT takes the position that its proposed project sizes will allow for a "bigger pool of market participants, resulting in potentially greater diversity...." It is unclear from the narrative why DBEDT believes larger project sizes would increase diversity. To the extent that the Commission approves an annual system limit, then the opposite would be true, larger project sizes (relative to those proposed in the Proposed FIT) would result in fewer projects under the system limits. In addition, diversity implies various technologies or various locations; diversity is not increased simply by the number of projects coming onto the grid if they are correlated in output or clustered in a location.

With regard to item (b) (Id.), DBEDT states that "a greater number of relatively small distributed generation will potentially provide system benefits by helping replace central generation stations and improving grid operation and reliability." This appears to reflect a significant technical misunderstanding. Displacing centralized generation with distributed resources does not improve grid reliability. In fact, such an action would serve to increase costs and reduce reliability. This is because distributed resources are more difficult to control because the distributed resources that are being discussed do not provide the inertial response or firm dispatchable energy capabilities of transmission-sited generation due to the fact that these resources are connected on the distribution system and thus are radially connected. Unless these resources are equipped with an expanded interface they will be subject to mis-trips during system faults. Transmission-sited generators provide benefits due to being on the transmission interconnection. It also must be understood that PV, and other variable renewable energy resources by themselves generally do not provide the firm capacity, load following, and voltage regulation necessary to maintain a stable and reliable power system. Therefore distributed PV must be limited to a relatively small percentage of the total system energy and is not capable in and of itself of achieving very high penetrations levels for renewable energy.

With regard to item (c) (Id. At 55), DBEDT asserts that "replacing central generation stations with renewable distributed generation will also reduce line losses...." Replacing central generation stations with renewable distributed generation does not necessarily reduce losses. Distributed generation can reduce losses on the distribution system when sized according to the load on the distribution circuit. However, once distributed generation exports power to other users; i.e.; once distributed energy is moving from the distribution circuit up to the transmission system to serve customers outside the distribution circuit (which may occur given the project sizes proposed by DBEDT), then it is subject to the same losses as any power flow through the power system. Exporting power to the transmission system also creates various technical issues that must be resolved at non-trivial expense (controls, monitoring, protection system, and modifications of voltage regulation).

With regard to item (d) (Id.), DBEDT states that its proposed project sizes will "attract more local market participants or developers...." However, DBEDT provides no evidence of any kind to support this general proposition that project size is correlated with attracting local market participants. With regard to item (e) (Id.), while DBEDT states that its proposed project sizes are "easier to site relative to much larger project sizes" it ignores the fact that by that same logic, DBEDT's proposed project sizes will be more difficult to site than projects in the size range proposed by the Joint Parties in the Proposed FIT. The Joint Parties generally do not dispute DBEDT's statement at item (f).

With regard to item (g) (Id at 55-56), DBEDT states that its proposed 5 MW project size for Oahu is reasonable based on "HECO's <u>system</u> load" (emphasis supplied). DBEDT, like other intervenors, appears to confuse project size limits and system level capacity limits for FIT projects. A purpose of the Proposed FITs' project size limits for individual projects is to develop a FIT which would apply to projects that required minimal, and therefore standardizable interface requirements, and to limit projects to those sizes that would require, in general, minimal study due to their relative size on the distribution circuit. Thus, the consideration of the size limit for individual projects pertains to the typical circuit size on the power system, not the system load. The system load, and amount of existing variable generation, would be a consideration in the derivation of the *total* system limit. If the project size were to be increased, it is likely that the minimum technical interface requirements would also have to increase to ensure that the unique concerns pertaining to large generators on the distribution system (relative to the native demand on the distribution circuit) could be addressed. In order to keep the interface requirements simple, then the projects must be kept relatively small. As mentioned above in response to item (a), limiting project size will result in a greater number of projects to meet the same system threshold, which would also tend to maximize diversity and minimize the impact of the variable generation.

With regard to item (h) (Id. At 56-57), the 15% limit discussed is used in the industry for the purpose of defining a threshold above which additional study is required to determine the impact of the aggregate distributed generation on the circuit to which it is connected and for larger penetrations, on the power system as a whole. This screening process is used to ensure that situations where generation is large enough relative to demand on the circuit, which can occur at any time of day but often occurs during minimum load periods, does not cause technical problems including damage to the generation and customers equipment on the circuit, as well as damage to utility equipment. This threshold does not preclude the addition of larger generators on distribution circuits, but does preclude them from being connected without additional study. This is a prudent measure and commonly accepted in the industry. In contrast, it is not clear how the discussion captured in item (h), which appears to be based on some system-level load demand assumption, addresses the technical problems created by the potential for unintentional islanding, and voltage problems that would occur if the distributed generation on a circuit is large relative to the load on that circuit (at any time of day) and that circuit should open for a fault. The discussion at item (h) also does not address the issues that arise to the extent the distributed generation is able to export from the circuit onto the transmission system.

Finally, there is a discussion at the end of the foregoing DBEDT sections on project sizes that bears clarification. First, DBEDT notes that the load on HECO's 12 kV circuits at peak ranges from 400 kW to 13MW. DBEDT cites to this statistic for the proposition that the "upper limit" of that range is "almost 3 times the proposed 5 MW project size for Oahu." (Id. at 57) However, the more relevant standard is the minimum demand on the circuits which may not be supportive of DBEDT's assertion. Second, DBEDT also mentions sub-transmission circuits and that relatively larger project sizes may have to be interconnected at this level. Since sub-transmission circuits can go through various configurations, and generally serve assorted distribution systems, the loading on the sub-transmission circuit must include consideration of all generation in the aggregate, is more complicated than a typical distribution circuit, and therefore also would require study to determine whether the project sizes proposed by DBEDT could be accommodated. Third, DBEDT's use of the non-coincident peak demand ("NCD") figure at page 57 of its Opening Brief is inaccurate. DBEDT states that the total NCD of 26,215 MW is a "close approximation of the total peak loads on the distribution circuits." HECO has approximately 400 distribution circuits, therefore, by DBEDT's assumption, each circuit is loaded to 65.5 MW which is not electrically possible at the 12kV level.

D. The HECO Companies Must Follow The Reliability Standards Established By The Commission In General Order 7.

The intervenor parties allege (1) that the HECO Companies do not have reliability standards to support the limitations set forth in the Joint Parties' Proposed FIT (SA/HSEA Opening Brief at footnote 19); (2) the Commission should direct the HECO Companies to develop standards to clarify what constitutes grid system reliability (Sopogy Opening Brief at 14-15); and (3) that the HECO Companies did not provide any evidence of quantitative reliability goals (DBEDT Opening Brief at 45);

During the panel hearings, the HECO and HELCO system operators provided extensive testimony on the reliability standards which they endeavor to meet each day. (See, generally, Panel Hearing Transcript at I-179, line 18 through approximately I-206, line 22) (This included testimony regarding the fact that the system operators routinely work to maintain system frequency, survive system contingencies, avoid outages and avoid total system failure). (Id.) Moreover, in response to a request from the Commission's panel hearing moderator, the Joint Parties presented through their Opening Brief an extensive description of their work in complying with the Commission's General Order No. 7 which contains the broad reliability standards for voltage, frequency and reliability that the Hawaii utilities are required to comply with. (See, Joint Parties' Opening Brief at 30-38) Additionally, the HECO Companies regularly submit reports to the Commission for the purpose of informing the Commission of its reliability performance. These reports include the Customer Average Interruption Duration Index which measures the average amount of time a customer is without power per interruption; the System Average Interruption Frequency Index which is a measure of the number of times the average customer experiences an interruption in supply; the System Average Interruption Duration Index which measures the number of minutes over the year that the average customer is without power; and the Average System Availability Index which is a measure of the overall reliability of the system representing the percent of time during the year that the average customer has power.

Accordingly, there are explicit Commission reliability standards which support the initial limitations set forth in the Proposed FIT, and the HECO Companies' responsibility is to comply with those standards already established by the Commission. As discussed extensively in the Proposed FIT, Joint FSOP and Opening Brief, this is a significant goal of the Proposed FIT design.

E. Pricing Data Used To Establish Initial FIT Prices Should Be Evaluated To Insure That They Represent Arms Length Transactions Without Undue Political Or Other Influences Which Could Result In Windfall Profits To Developers.

SA/HSEA state that their proposed FIT rates for PV technologies are below prices paid by the State Department of Transportation for certain PV contracts for airport roof projects. (SA/HSEA Opening Brief at 10) While the Joint Parties do not have detailed information regarding this transaction between the State and a private developer, the Commission should endeavor to understand the details of the transaction, including any motivations other than price to enter into the contracts, prior to approving or adopting the SA/HSEA proposed rates.

Although the information would have to be independently verified, the Joint Parties note that in a recent Honolulu Advertiser article concerning the very projects which SA/HSEA cite to, the following observations were made:

- Taxpayers are paying what could amount to a multimillion-dollar premium for power from recently installed solar panels on the roofs of state-owned buildings, including several airports.

- The rate the state pays for solar power is not only more than what it would pay for traditional electricity, it's nearly twice what private consumers pay for solar energy in today's market.

- The state negotiated a price when the cost of power was near its recent peak and locked it in for 20 years. It also failed to get a large number of competitive bids, which could have lowered the price, industry officials said.

- "The state is definitely paying too much for electricity at least on the airport projects," said Sean Mullen, president of solar power integrator Suntech Hawaii. "It's twice as high as it should be." (Note that Suntech Hawaii is a member of HSEA.)

- The state signed 20-year power purchase agreements with Hoku Scientific Inc. last fall. Under the agreements, the state is paying 38 cents a kilowatt hour on Maui and Kaua'i for solar power. In Hilo the rate is 33 cents a kilowatt hour, and in Kona the rate is 32 cents a kilowatt hour. Hawaiian Electric Co.'s rates for medium and large customers on Maui this month vary from 16 cents to 21 cents a kilowatt hour. Two local solar power companies surveyed by The Advertiser said comparable power purchase agreements today sell electricity for 20 cents to 22.5 cents a kilowatt hour.

- Suntech's Mullen agreed that the state could have gotten more competitive prices by issuing a new request for proposals after the deal with SunPower fell through.

Hawaii paying nearly twice market rate for solar power, Honolulu Advertiser, Sunday, June 21, 2009.

As outlined in their Opening Brief, the Joint Parties believe that pricing for FIT resources should be determined by using a Discounted Cash Flow analysis methodology to assess costs of generation and the return on investment and Internal Rate of Return for the project over the life of the system. (Joint Parties' Opening Brief at 57) However, the Commission should not accept generalized statements regarding the appropriateness of various pricing proposals without endeavoring to insure that the prices adopted ultimately are just and reasonable for Hawaii ratepayers considering all applicable factors. Moreover, although HDA takes the position that the "just and reasonable" standard should continue to apply "only to the utility and its customers, not to independent power producers" (HDA Opening Brief at 5) it is apparent that the rates paid to independent power producers are an important component in the utility's ability to ensure that its charges to ratepayers are just and reasonable.

F. Proposals For The Appropriate Return On Equity That Should Apply To FIT Rates Must Demonstrate That The Return Proposed Is Just And Reasonable And Supported By Documentation Indicating That The Data Provided In Support Of The Proposed Rate Is Accurate, Reliable And Relevant To The Hawaii Market.

As discussed in the Joint Parties' Opening Brief, it is ultimately the developers of projects that are in the best position to provide the Commission with relevant information regarding a reasonable rate of return for a particular project or type of project. (Joint Parties' Opening Brief at 54) A reasonable caveat on this position is that the information provided by the developer should be appropriately supported with documentation to demonstrate to the Commission's satisfaction and parties' satisfaction that the information is accurate, reliable and relevant to the Hawaii market. To the extent that the parties desire different returns for different projects to reflect varying risk, objectives, and cost of capital for different technologies, they should be directed to provide evidence in support of the differing returns that they seek.

In contrast to the need for detailed information to support a proposed rate of return, SA/HSEA take the position that the Commission should adopt as a baseline the Commission-authorized return for HECO of 10.67 percent. (SA/HSEA Opening Brief at 12)[21] SA/HSEA take the position that since this represents a "riskless" level of return, then any rate of return allowed the developers in this proceeding must clearly exceed that rate to account for the risk that the developer will encounter. (Id.) SA/HSEA's assertion is flawed. As the Commission is well aware, the setting of a utility's authorized rate of return is a complex and detailed matter which is premised in large part upon a full disclosure of the utility's costs and revenues, and incorporates as a part of that analysis consideration of the various risks facing the utility. It must also be noted that the authorized rate of return cited by SA/HSEA is just that, the "authorized" rate of return, which is by no means a guarantee that the utility will be able to earn that return. This is far different from the situation facing a private entity which could in fact have an entirely different risk profile than a utility, including lower risks that would allow it to reap significant profit using a utility authorized rate of return. The utility's authorized rate of return is by no means "riskless" and therefore the Commission must consider this fact in evaluating the assertion by SA/HSEA. As discussed above, the more prudent approach is to determine the correct rate of return for the projects at issue based upon appropriate data supported by documentation which demonstrates that the data is accurate, reliable and relevant to the Hawaii market. This is the reasonable way to proceed as opposed to an apples to oranges comparison between a project developer and a regulated utility.

G. A Measure Of 15% Of Distributed Generation Of Any Kind On An Individual Circuit Provides A Reasonable Point At Which An Informal Circuit Study Is Required To Insure System Security.

SA/HSEA proposes penetration limits of 15% per distribution level circuit as a reasonable place to start with regard to the available capacity that a system has to integrate a renewable energy resource. (SA/HSEA Opening Brief at 15) This benchmark serves as a "trigger" point at which it is reasonable to conduct a system study to insure that integration of the resource does not cause reliability, power quality or safety concerns.

Sopogy proposes a goal of raising the circuit penetration limit to 50% within six years of implementation of a FIT program. (Sopogy Opening Brief at 9) Expansion of the circuit

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[21] HREA also takes this position. (HREA Opening Brief at 17)

penetration limits should be examined after the Commission, utilities and parties have some experience with the 15% circuit penetration level, the interaction of that penetration level with the Proposed FIT and other renewable energy procurement programs, and have an opportunity to monitor the effects of that trigger level. This can be done through the FIT Update process which may capture Sopogy's goal of achieving this expansion within a six year period. The level of penetration proposed by Sopogy would require additional technical study as well as possible system infrastructure modifications to insure system stability and security.

It should be noted that the current Commission-approved Rule 14H requires an additional technical study for penetration beyond 10% of the peak load in order to maintain proper safety, reliability, and power quality levels. This 10% of system peak is an approximation for the industry rule of thumb that the generation be not more than 33.3% (1/3) of the circuit minimum load. Thus, if the generation is higher than 33.3% of the minimum load the industry rule of thumb indicates that anti-islanding and other protective relays will not be able to mitigate problems on the grid in a reasonable time period. A detailed circuit analysis including but not limited to feeder load flow, dynamic stability analysis, transient overvoltage, short circuit and relay coordination may need to be performed in order to evaluate the risk of voltage problems, protection malfunction from reverse power flow, and unintended islanding. The penetration level proposed by Sopogy would also likely require extensive communications for transfer trip, monitoring, and control, and perhaps additional capabilities from the distributed generators for grid management services. Even with these modifications, the overall impact on power system stability and balancing for the overall aggregate amount of distributed generation would need to be evaluated and set in context as to whether achieving these goals would in fact achieve the preferred generation mix in order to achieve the overarching goals of maximum renewable energy penetration while maintaining reasonable cost and reliability.

H. The Commission Should Begin With Adoption Of The Tier 1 Joint Proposal And To The Extent It Desires To Expand Upon The Initial FIT, It Should Commit To A Tier 2 FIT As Part Of The First FIT Update In Two Years.

SA/HSEA proposes a three-tier proposal for the FIT which would incorporate both different tiers of eligible project sizes as well as interconnection requirements. (SA/HSEA Opening Brief at 17-18) The SA/HSEA proposal raises a number of issues. First, the proposed project sizes can be problematic for the reasons discussed above. In particular, non-curtailable generation has the potential to increase curtailment to existing renewable energy projects. Moreover, the SA/HSEA proposal increases ratepayer risk. Put simply, allowing developers to avoid the reasonable cost of interconnection and other studies and project costs would open the door to developers submitting any number of project proposals regardless of practicality, economics or engineering. Utility resources would be adversely affected by frivolous proposals and drawn away from processing viable economic projects. Also, bearing the cost of system, substation and SCADA for some of these projects puts an undue financial risk on the utilities and their customers. As an example, if the utilities are required to pay for a substation for a project and the project does not materialize or is not able to continue operations for whatever reason, the utilities, and ultimately the ratepayers, will have paid for something that is no longer useful. Without financial risk to the developers, there is little to prevent developers from pulling up stakes at any point during the project and leaving the utility bearing the costs of an unusable facility. With no financial burden, developers could also propose new generation sites far from compatible grid resources, requiring the utility to construct costly system facility upgrades.

The Joint Parties respectfully offer that a more reasonable allocation of the costs of interconnection be established as set forth in the HECO Companies and Consumer Advocate's Opening Brief. (Joint Parties' Opening Brief at 62) The Joint Parties' proposal fairly allocates the costs associated with interconnecting a new generation facility between the utility and developer allowing both for the facilitation of new interconnections based upon defined obligations and the avoidance of the negative consequences described above.

As an alternative to the SA/HSEA proposal, it must be noted that the Proposed FIT does not foreclose the possibility of accommodating larger projects in the future. In fact, because of the greater flexibility provided by the Oahu grid, HECO supports the notion that a FIT can be established for larger projects of certain technologies on Oahu, perhaps up to the 5 MW threshold for the Framework for Competitive Bidding. Before establishing such a FIT, however, appropriate energy pricing for such projects and interconnection requirements must be established, as projects of this size have not heretofore been developed in Hawaii.

As discussed in the Joint Parties' Opening Brief, regarding pricing, HECO believes that the most appropriate mechanism to establish a sound pricing basis for a future FIT for larger resources up to the 5 MW limit of the Competitive Bidding Framework is to conduct a competitive solicitation for such resources in the near term for Oahu. (Joint Parties' Opening Brief at 41) Such a solicitation could be prepared and issued in a relatively quick timeframe – in a matter of several months – to provide valuable pricing information well in time to be considered in the first FIT Update two years from the initial establishment of the FIT. Alternatively, to the extent that the utility is able to secure appropriately detailed and publicly disclosable cost data as a result of bilateral negotiations with Hawaii based projects, this data may also serve as a pricing resource.

Furthermore, if HECO is able to reach agreement with owners of large land areas willing to provide their sites for renewable energy development, the solicitation could target development of multiple 5 MW or smaller renewable projects consolidated in one or more geographic areas. Such an approach would allow greater efficiency in conducting interconnection requirements studies, development of common electrical infrastructure to support interconnection of the multiple projects, and negotiation of land use agreements between the land owners and renewable developers. HECO is currently evaluating the construct of a request for proposals ("RFP") to develop multiple PV farms of 5 MW or less on Oahu which could be issued in the near future, to support project developments in the 2010 - 2011 timeframe as well as establish a FIT for larger PV installations by the time of the first FIT Update. Note that HECO is not proposing that competitive bidding be used as the preferred contracting mechanism for projects of such sizes on a continuing basis. To the contrary, the RFP would be intended as a means to establish a sound basis for development of the FIT for larger resources.

Regarding interconnection, the Joint Parties have presented clear evidence of the difficulty in standardizing interconnection reviews and requirements for projects larger than those provided in the Proposed FIT. Unlike the Proposed FIT, a FIT for larger resources could not feasibly assume standard interconnection requirements or costs. As such, if a FIT is developed for larger resources on Oahu, it would be necessary to bifurcate the interconnection review process and corresponding interconnection contractual requirements from the non-interconnection issues and contract terms and conditions (including pricing) which could be included in a FIT. HECO is willing to give further consideration to this approach, in the interests of supporting the development of a FIT for larger resources on Oahu in the first FIT Update.

I. Annual Targets Should Reflect The Ability Of The Grid Which The Resource Seeks To Integrate To Accept That Level Of Renewable Resource.

As discussed in the Joint Parties' Opening Brief, the amount of variable generation that can be accepted on a power system is ultimately dependent upon various factors such as: (1) the characteristics of the variable generation such as rate of change, correlation with other resources, degree of possible change in a given time period, predictability of output, and control capabilities; (2) the characteristics of the other controllable or dispatchable resources such as available ramp rate, frequency response, minimum load, and startup time; (3) the minimum number of conventional generators which are necessary to provide for the reliable operation of the power system: as necessary to survive reasonably probable faults and disturbances, ability to regulate voltages, perform load balancing and frequency control; (4) the operational configuration to mitigate reliability impacts and their costs, for example, the inclusion of increased reserves (minimizing displacement of dispatchable units); (5) evaluation of possible technical solutions and their costs such as supplemental controls on the variable generation, modification of the dispatchable generation, infrastructure modifications; and (6) establishing minimum reliability criteria to be maintained on the power system

SA/HSEA proposes that an annual target for FIT renewable penetration be set at 15% of the 2008 peak demand of each utility. (SA/HSEA Opening Brief at 20) Sopogy supports this proposal and also proposes that increased levels of penetration be set at each two year program review period starting with a limit of 470 MW for the HECO Companies. (Sopogy Opening Brief at 3). Both SA/HSEA and Sopogy make their proposals without any consideration of the factors described above or any evidence that their proposals can be implemented by the utilities. One example of the flaw in the intervenor proposals is that the 15% limit that they reference is the distribution circuit limit level at which additional circuit study would be required to insure that the resource to be integrated does not unduly cause security or power quality concerns. SA/HSEA and Sopogy seek to apply this limit to the system peak demand as a basis for determining an appropriate annual system limit upon new renewable energy projects coming in under a FIT program.

With regard solely to the distribution circuit trigger, it must be noted that this applies to all distributed generation on a particular circuit and not just the generation that comes in through the FIT program. Therefore there needs to be an understanding that a circuit or number of circuits may be fully subscribed in terms of available FIT capacity. Additionally, due to changing load demand, it is possible for a circuit which may have been under the 15% threshold for distributed generation to subsequently be at a level higher than the 15% threshold if load vacates the system for whatever reason.

With regard to the proposed system penetration limits, these cannot be determined in a vacuum but instead must appropriately and comprehensively account for each of the factors described above. These factors must be evaluated in order to have even a general concept as to the amount of variable generation that can be accepted on a power system. As has been stated in this proceeding (and presented through the supplemental information submitted to the Commission on May 8, 2009) the HECO Companies have conducted and are in the process of conducting studies for the express purpose of evaluating this issue and being able to have more comprehensive information as this issue is considered through the FIT Update process. The SA/HSEA and Sopogy proposals do not consider or even discuss these issues and therefore, there proposals should be rejected by the Commission as unsupported and without merit.

Finally, in response to Sopogy's proposal, it should be acknowledged that any proposed limits on system penetration are not subject to change based on calendar time but only based upon appropriate study and evaluation of system impacts.

Related to this issue, the Zero Emissions LLC ("ZEL") Opening Brief outlines several clean energy scenarios for feed-in tariff resources. It is the Joint Parties' position that the formal clean energy scenario planning process, which is ongoing in a separate docket, will be important to the success of renewable energy development in Hawaii. ZEL raises several important issues which should be taken into account in the formal process, but ZEL makes several methodological choices that may not accurately inform policy design.

ZEL implies that the existence of caps will dramatically increase the policy costs of a feed-in tariff in Hawaii because of increases in financing costs. The projected financing cost increases in the HECO FIT scenario negate the ancillary benefits ascribed to renewable generation. This characterization seems incorrect. Although caps and limitations may not be the preferred design for project financiers, caps can be implemented without incurring significant financing cost impacts as long as the procedures related to the caps and any related queuing procedures are transparent, clear, and easily understood by financiers.[22]

The Joint Parties note that the relevant sections of the de Jager and Rathmann study cited by ZEL as the basis for the financing cost estimates do not address caps. The 10%-30% levelized price impact does not relate to whether or not caps are in place, and the specific example listed in footnote #21 attributes the 30% increase in financing costs in the "default case" to "a

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[22] Karcher, M. (2009, May 28). Feed-in Tariff Design Implications for Financing of Renewable Energy Projects Over 20 MW. Presented at the California Energy Commission Integrated Energy Policy Report Feed-in Tariff Workshop.

consequence of the design (feed-in vs. feed-in premium) and period (20 year in Germany and France, 5 year in California) of the main support scheme" – but not to caps. Generally speaking, policy limitations do not significantly increase financial risk, and therefore financing costs, as long as they are transparent and clear.

It is important to note that, although the question of cap magnitude is still under discussion, most parties in the proceedings, including intervenors such as the Solar Alliance and the Hawaii Solar Energy Association acknowledge that a cap of some kind will be necessary, given Hawaii's unique grid infrastructure challenges.[23] Given the lack of evidence to support the financing cost figures, and the necessity of some kind of cap to ensure grid stability, the Joint Parties do not view ZEL's assessment of financing cost impacts as a realistic assessment of conditions in Hawaii.

A second issue of concern is the issue of ancillary benefits ascribed to renewable resources in Hawaii. The Joint Parties believe that carefully sited renewable generation, designed and constructed in a manner compatible with island grids such as HECO's can provide benefits to the grid, to society, and to the ratepayer. These benefits, however, are location and technology specific and have the potential to benefit different stakeholders in different ways. ZEL cites several sets of benefits, which it employs in a cost/benefit calculation for each FIT. The PV benefits, however, are based on a study completed for California, whereas the effective load carrying capacity calculations used to calculate the benefits of other renewable resources are also based on a California study.[24] Hawaii has dramatically different electrical infrastructure

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[23] SA/HSEA Opening Brief at 20.

[24] Americans for Solar Power (2005). Build-up of PV Value in California; Milligan, M., Kirby, B., Jackson, K., and Shiu, H., "California Reneawbles Portfolio Standard Renewable Generation Integration Cost Study: Multi-Year Analysis."

from that of California and it is questionable whether California studies can be accurately applied to the Hawaii context. A third source cited by ZEL – a report from the National Renewable Energy Laboratory (NREL)[25] – illustrates the importance of contextualizing cost/benefit analyses. The NREL study reviews a hypothetical case in which the net present value of a 5 kW PV system is positive for the customer that installs it, but negative for society and for the utility and ratepayer, even after all the additional benefits and values are taken into account. In other words, the PV development benefits some stakeholders, and can represent a cost to others. It is therefore important, when conducting a cost/benefit analysis, to recognize that not all benefits are additive across all stakeholder sets. The goal of the above discussion is not to dispute the value of renewable generation or to downplay the importance of a transition to renewable energy, but to illustrate the importance of understanding Hawaii's specific context. Without a better understanding of Hawaii's electrical grid infrastructure, it would be unwise to base energy policy and planning decisions on calculations drawn from broad research conducted for other jurisdictions. Until the full costs, benefits, risks, and rewards of unbounded renewable energy development in Hawaii are understood, the Joint Parties favor an iterative approach to feed-in tariff implementation in order to better understand and assess the limitations of the grid as the state renewable energy market expands.

J. Transmission Level Projects Should Not Be Eligible For The Initial FIT And Should Be Procured Through Other Mechanisms.

The Proposed FIT focuses on distribution level projects in part due to the complexity associated with evaluating transmission level projects and the fact that this complexity makes

[25] Contreras, J.L., Frantzis, L., Blazewicz, S., Pinault, D., & Sawyer, H. (2008). Photovoltaics value analysis. (NREL/SR-581-42303). Golden, CO : National Renewable Energy Laboratory.

these size projects amenable to other procurement alternatives and not a streamlined, standardized FIT. Project interconnection issues at the transmission level are in many respects different from the interconnection issues which have been discussed in this proceeding for distribution level projects. The transmission issues are normally related to circuit capacity rather than demand since transmission is networked and the demand is shared among all transmission circuits based upon the system power flow. Nevertheless, SA/HSEA and Sopogy propose a 15% penetration limit for FIT renewable energy at the transmission level. While this proposal should not be considered for the reasons stated it must be pointed out that any such limit would also apply to all transmission level projects (not just those that could conceivably come in through a FIT program) and therefore, in many cases, the utilities have already achieved penetration levels well in excess of the 15% threshold.

As discussed above, the intervenors' proposals also indicate some confusion between circuit-level limits, and system level limits. For circuit-level limits, 15% of the peak demand on the circuit would or could be a limit that the utilities may designate as requiring additional interconnection study as it indicates that distributed generation is getting large with respect to the load on the circuit. This creates technical issues which must be addressed to protect the loads and generators on that circuit from damage should the distribution breaker open, and requires protection reviews. To the extent that the intervenors are intending that the utility should target 15% of the utility peak demand to be distributed generation, they are referencing system-level penetration. The CESP process should determine the optimal mix of generation on the utility grids but 15% of the total energy from distributed resources would quite likely create significant issues that require resolution such as the monitoring and control of the distributed resources and an understanding of the aggregate variability if such resources are primarily variable PV.

The Joint Parties did not propose a FIT for transmission-interconnected resources because for the majority of these resources the Competitive Bidding Framework would apply and is a superior process again due to the complexity associated with interconnecting projects at the transmission level, as well as the difficulty associated with standardizing the terms and conditions for such projects. To the extent that such an expansion of the Proposed FIT is to be considered in a future FIT Update, extensive study should be performed regarding system impacts potentially arising from the transmission connected generator and to insure that the transmission system infrastructure remains operable for contingencies and routine outages.

K. Before Establishing A "Market Penetration Framework" The Commission Must Have Some Idea Of The Penetration Levels Which Different Rates Will Promote Constrained By The Ability Of The Grid To Take On The Resources.

SA/HSEA proposes a "Market Penetration Framework" at page 20-23 of their Opening Brief. While the HECO Companies and Consumer Advocate have not had the opportunity to explore the details of this proposal, on its face the proposal appears contrary to the agreement of the parties to the Energy Agreement that FIT rates would be set to recover the developer's cost plus a reasonable level of profit. As structured, it appears that the SA/HSEA proposal would perhaps artificially incent a rush of new projects quickly through a rate which may not be reflective solely of the developer's cost plus that reasonable level of profit. It is the position of the Joint Parties that the Commission's FIT pricing should reflect the agreement of the parties to the Energy Agreement as this level of pricing already provides a significant benefit to the developer in terms of cost recovery and profit. To the extent that technology matures and the cost of these resources decreases over time, then perhaps the FIT rates can be reset to a lower level as a part of the FIT Update process. FIT rates should not be structured to achieve some artificial acceleration. Moreover, there are clear benefits to the Proposed FIT in that it will allow for simplicity and ease of program implementation and administration in contrast to SA/HSEA's proposed digression structure. The Commission must achieve an appropriate balance in setting FIT rates between incenting new renewable generation under the FIT while at the same time not providing undue windfall profits to developers at the expense of ratepayers.

L. The Ratepayer Is Paying For The Developer's Cost And A Reasonable Profit In Exchange For Renewable Energy And Associated Environmental Attributes Including Renewable Energy Credits.

It is the Joint Parties' position that any Renewable Energy Credits associated with electricity purchased under feed-in tariff rates in Hawaii should be transferred to the utility, for the benefit of ratepayers, and retired. The automatic transfer and retirement of RECs under a feed-in tariff that is both (a) based on generation cost and (b) used to meet renewable portfolio standard (RPS) targets is consistent both with national best practices related to REC markets and with the interests of the ratepayer. Hawaii does not currently have an active or formal REC market, and utilities are not explicitly required to purchase RECs in order to demonstrate compliance with the state RPS. As a result, several of the intervenors have asserted that "Ownership of Renewable Energy Credits ("REC") are an asset to the Developer of the renewable generating facility and as such are not part of the FIT rate.[26]"

Although Hawaii does not have an established REC market and RECs are not explicitly defined as the basis for RPS compliance, the Energy Agreement states that "Utility purchases of renewable energy under the feed-in tariff shall be counted toward the utility's Renewable Portfolio Standard requirements." Because utility purchases of the feed-in tariff will be counted

[26] *See*, e.g. SA/HSEA Opening Brief at 24; also, HREA Opening Brief at 21.

towards the RPS requirements, there is a strong argument to be made that any RECs would automatically and implicitly transfer to the utility and be retired on behalf of the RPS target and on behalf of the ratepayers.

The Center for Resource Solutions, a non-profit organization which oversees the Green-e consumer protection program for REC products,[27] has published the *Regulator's Handbook on Tradable Renewable Certificates.*[28] The *Handbook* is clear that utilities cannot claim renewable resources to be part of their system mix if another party retains ownership to the RECs.
"In the event that a utility is...buying the output, but not the [RECs], from a renewable generator...the renewable attributes of the generating unit should not be included in the calculation of the utility system mix. The reason for this is that the utility has no legal right to claim the renewable attributes or to represent the kWhs as renewable on their disclosure label."

Using the same logic, it seems clear that allowing a generator to maintain ownership of the REC when the utility is including the same generation in the utility system mix would result in a case of double counting. Consider the following hypothetical example. A utility is obligated to purchase renewable resources for a certain percentage of its portfolio. It purchases the electricity from a wind generator and claims that 1% of its portfolio is generated from renewable resources. The wind generator retains the ownership to its RECs, however, and sells them on the voluntary market to a government facility. Since the government facility is a customer of the utility, it can claim that 1% of its power is derived from renewable resources (through the utility portfolio), and that it has purchased additional green power directly from the generator. The government facility has effectively counted the same power twice.

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27 *See* http://www.green-e.org/

Since the feed-in tariff resources are counted towards the utility targets, resale of the RECs would not support any additional renewable energy capacity – it would simply provide an additional revenue stream for generators. The US Environmental Protection Agency previously submitted comments to the Public Utility Commission of Texas that additionality is a critical component of REC sales,

> It is this incrementality (or additionality) requirement that gives voluntary green power purchases their environmental integrity and marketability. This concept has been recognized and endorsed by the National Association of Attorney Generals, the Federal Trade Commission, and the most prominent national certifier of green power products, the Center for Resource Solutions' Green-e Program, and is a widely accepted standard in the green power market. <u>Unless this requirement is met, it is inappropriate for green power to be marketed based upon its environmental benefits</u> because such benefits would have occurred – whether the purchase was made or not – due to the state's renewable energy mandate.[29]

Beyond the potential for double counting, a second significant concern with generators retaining REC ownership is that generators could receive windfall profits at the expense of ratepayers. As stated in the Energy Agreement and as reiterated throughout the proceedings, the feed-in tariffs should be based on the generation cost of each technology, plus a reasonable profit. In their Opening Brief, for example, SA/HSEA argues that profit should be set to be "meaningfully higher than the 10.67 percent level." If generators were allowed to retain ownership of their RECs, they could conceivably sell the RECs in some future market and earn additional revenue above and beyond the amount needed to recover their generation cost, plus a reasonable profit. This would represent a windfall profit for generators. The suggestion that "The FIT rate would need to be adjusted higher if the Utility would like to purchase the REC" would also represent a windfall profit for generators, but at the direct expense of Hawaii ratepayers. Under a generation

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[28] Hamrin, J. & Wingate, M. (2003). Regulator's Handbook on Tradable Renewable Certificates. San Francisco, CA: Center for Resource Solutions.

cost-based FIT, any additional value received by the generator (e.g. from future REC revenues, etc.) would need to be subtracted from the FIT rate, not added to it. Per the Joint Parties' position above, however, it should be irrelevant whether to add or subtract REC value from the feed-in tariff, since the REC already should implicitly transfer to the utility as part of the feed-in tariff transaction and the FIT rate is designed to provide full cost recovery plus a reasonable profit.[30]

Notably, DBEDT is supportive of this position in its Opening Brief. As discussed by DBEDT, "the renewable energy purchased by the HECO Companies through the FIT program should count toward the utilities' renewable portfolio standards (RPS)." This means that the renewable energy purchased through the FIT "shall include the renewable energy credits or green attributes of such purchased renewable energy." (DBEDT Opening Brief at 62) As explained by DBEDT, the cost-based determination of the FIT rates already compensates the developer for the cost of the project, and DBEDT does not believe developers should also be compensated for some presumed value of the project's green attributes based on an expectation of some future market for such attributes unbundled from the kilowatt-hours produced by the project." (DBEDT Opening Brief at 62-63). Moreover, DBEDT confirmed its understanding that the green attributes of a renewable resource cannot be both counted toward an RPS goal and sold again in a developed RECs market. It is therefore DBEDT's recommendation that the determination of the FIT rates should not impute any additional value for the green attributes of the renewable energy purchased by the HECO Companies through the FIT program because the green attributes of the renewable power being purchased through the FIT program is a resource characteristic that

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[29] Hogan, K. (2006). Comments of the U.S. Environmental Protection Agency. Submitted to the Public Utility Commission of Texas (Rulemaking Related to Renewable Energy Amendments, Project No. 31852).

makes the project eligible under the FIT program. As DBEDT made clear in its Brief, "the determination of the FITs rates is based on the project cost plus reasonable return, and it is not a "value-based" method." (DBEDT Opening Brief at 63) The presumption of a future market for RECs should not be used as a basis for inputing any value for RECs in the determination of FIT rates, as there is no evidence in the record as to the basis of such a presumption or how such a market would value RECs.

M. The Parties Should Work Together To Develop A Fair And Transparent Queuing System That Reflects The Unique Operating Characteristics Of Hawaii's Island Grid System In General And The HECO Companies' Various Renewable Energy Procurement Vehicles In Particular.

Sopogy proposes that the Commission consider either the Midwest Independent System Operator or California Solar Initiative models in the Commission's determination of an appropriate queuing process for the FIT program. (Sopogy Opening Brief at 12) Sopogy also suggests that the queue process to be developed encompass the FIT program, competitive bidding, non-bid PPAs and NEM and that the Commission utilize an independent third party to manage the queuing process. (Id.) (See also, HREA Opening Brief at 23)

The Joint Parties agree that an evaluation of appropriate queuing procedures and the costs associated with such a process is a sound concept. The Joint Parties disagree however that any queuing process necessarily needs to encompass transmission system level projects procured through the Competitive Bidding Framework or through the non-bid PPA negotiation process. If required, transmission level projects could have their own queue managed by the utility's Transmission Planning Division. A distribution level queue should encompass projects managed

[30] This in contrast to SA/HSEA's position that the FIT rate "would need to be adjusted higher if the Utility would like to purchase the REC." (SA/HSEA Opening Brief at 24).

by the utility's Distribution Planning Division and could encompass projects coming through the FIT Program, as well as non-bid PPAs and competitive bidding at the distribution level and projects coming in through the FIT Update process and the utilities' proposed PV Host Program. To the extent that the sum of NEM projects begins to have significant effects on the distribution system, then that program may be incorporated as a part of the distribution level queue. For the purpose of the FIT system level limits, the queuing could be on the basis of first ready, first to connect but must also incorporate the up-front costs associated with this process.

The Joint Parties also agree that it may be helpful to retain an independent third party for the purpose of setting up the distribution level queuing process (establishment of tracking website and external communications) but disagree on whether a third-party is required for the actual administration of the program. It is the utility planning divisions, in coordination with the other applicable utility divisions charged with implementing the various utility energy procurement programs, that are in the best position both to determine, using the process established by the independent third party, whether a third party is indeed ready to connect as well as to handle any disputes that may arise as a result of that process.

N. Potential Adjustments To FIT Rates To Account For Performance Capabilities Such As The Ability To Be Curtailed Or Dispatched By The Utility System Operator Should Be Explored.

Sopogy takes the position that FIT projects should be paid for any curtailment. (Sopogy Opening Brief at 4) As discussed in the HECO Companies and Consumer Advocate's Opening Brief, the island nature of the HECO systems means that there is no export outlet for excess energy and accordingly, in cases where excess energy is present on the system, curtailment is required. The annual FIT quantity targets and requirements for curtailment of certain types of FIT resources must take this into account.

The inclusion of possible curtailment impacts on energy production in the FIT pricing warrants consideration. Estimating curtailments is a complex problem and is very difficult to calculate accurately. The estimate would require extensive modeling. It would involve several uncertainties, including estimations of the anticipated energy production, future system demand, future generation additions which might contribute to curtailments, and other system conditions. In addition, the consideration of possible curtailments in pricing would result in an unintended consequence of encouraging resources to come online with anticipated hours of non-production (which are compensated) because the output of the resource is not correlated with the system demand. The price paid would not reflect the true value of the energy to the system and consumers. Compensation for curtailment takes away the natural disincentive for adding excessive amounts of must-take energy to a system that will occur if the producer bears the costs of curtailment (through reduced sales). If curtailments are anticipated to be significant, then it is a clear indication that there is an excess amount of that type of energy on the power system or it is producing at the wrong time of day. The issues of excessive must-take energy extend beyond increased costs for the ratepayer -- another result is a less responsive power system that is more at risk to failure following disturbance, as it is constrained towards minimum dispatch on the responsive generation which reduces the ability of the system to respond to loss of load events.

Perhaps oversimplifying the issue, as-available energy IPPs can be curtailed (or their output can be interrupted) due to: (1) system problems, (a) caused by specific as-available energy facilities - failing to comply with power quality (or performance) standards; or (b) caused by variable energy in general - excessive frequency fluctuations; (2) grid constraints, (a) e.g., the line through which the IPP is interconnected to the grid is de-energized for service; or (b) e.g., the line through which the IPP is interconnected to the grid incurs a forced outage; and (3) excess energy situations.

In the case of (3) and perhaps 1(b), curtailment generally is implemented, by contract, in reverse chronological order. In order to do this, there has to be a mechanism to institute and remove curtailment. In recent and new PPAs, that mechanism is a curtailment control interface (with older PPAs, it may be done through a telephone call.) The PPA provisions to do this are far more extensive than those in the proposed feed-in tariff contract, which generally relies on disconnection. Thus, as noted in the response to HRD/HECO-IR-4, there are small, essentially "non-curtailable" resources, such as residential PV systems, for which installation of curtailment equipment may not be technically or economically feasible.

If the FIT projects are small, and the amount is limited each year, an argument might be made that the projects generally should not be subject to curtailment during excess energy situations (unless absolutely necessary). The Commission would have to agree that such small generation projects (such as Feed-in Tariff projects, etc.) that are allowed to be installed without curtailment controls would not be curtailed before other as-available energy IPPs (including existing IPPs) because it is not practical. However, the impact on existing IPP's, and on projects currently under development in a difficult financing environment would have to be considered.

A third method to address the issue is to address the payment rate prospectively to take into account the level of curtailment experienced in the past, to the extent that the experienced curtailment exceeds some expected threshold. This "make whole" method would be difficult to administer in practice, and would not address the issues of encouraging the "wrong" projects discussed above. In addition, curtailed energy can only be estimated, it cannot be "measured".

For example, the calculation of estimated curtailed energy for a wind farm is complicated, and requires extensive, time-sensitive data.

Therefore, it is recommended that any compensation to suppliers for potential curtailments be limited for these reasons. The need for curtailment for excess energy can be mitigated in a larger sense through targeting appropriate generation additions and limiting certain types of energy to avoid contributing must-take production during excess energy periods. This is encompassed through the Proposed FIT and the project sizes and limitations on annual resource penetration limits proposed therein. In addition, if the FIT concept is properly limited to smaller projects that do not present integration issues, and/or targets technologies that tend not to produce energy during periods that presently require curtailments for excess energy, then the issue of curtailment during excess energy periods can be minimized.

In summary, the HECO Companies curtail generation at times to maintain system reliability and to manage difficult system conditions such as minimum load and high wind generation. Under the Proposed FIT, the HECO Companies should have the ability to impose operational standards and requirements, including generation curtailment, in order to maintain system reliability and meet obligations to existing power purchase contracts. For that reason, it is proposed that a lower FIT rate would be paid for generators that do not have the ability or the willingness to curtail output upon the utility's request. Generators without curtailment provisions would also be subject to lower annual capacity targets or in certain circumstances could be precluded from eligibility for a FIT. As more experience is gained with FITs and the results become available from the technical studies outlined earlier, curtailment can be revisited in the initial FIT Update, as well as through subsequent reviews.

O. It May Be Appropriate To Develop A Pricing Structure For Ancillary Services And Firming Technologies, As A Part Of The First FIT Update.

Sopogy proposes that ancillary services and firming technologies such as storage should be priced separately (Sopogy Opening Brief at 5) The initial FIT should focus on technologies with which the HECO Companies have some commercial experience and can be efficiently accommodated through a FIT program. The level and value of grid benefits that energy storage can provide to the HECO Companies are not yet understood as performance, operations, and costs have not been demonstrated in commercial or R&D installations. In addition, the technology-specific and site-specific nature of energy storage applications creates uncertainty in determining whether it would be priced appropriately within a FIT. Therefore, the pricing of ancillary services and energy storage should not be included in the Initial FIT due to the lack of technical data to support its pricing in Hawaii. Further investigations are needed to better understand and quantify ancillary services. Technologies that provide integration support for renewable energy projects may best be funded via the proposed Clean Energy Infrastructure Program.

It is also premature to include a Battery Feed-In Tariff (BFIT) rate as proposed by Clean Energy Maui ("CEM") (CEM Opening Brief at 6-8) in the Initial FIT since performance, operations, and costs have not been adequately demonstrated in commercial or R&D installations. It is undetermined at this time which energy storage solutions are best suited to support renewable energy integration. Moreover, there are technical and developmental uncertainties with regards to technology selection and sizing, controls, integration, siting, performance, operations and maintenance requirements, interconnection requirements, and costs, that put the electric utility (and ratepayers) at undue risk should unsubstantiated FIT rates be established for ancillary services and energy storage.

P. Use Of The Point Of Interconnection With The Utility Grid As A Point Of Demarcation For The Allocation Of Certain Interconnection Costs Is Acceptable To The Extent The Project At Issue Is A "Typical" Project.

Sopogy proposes that the developer bear interconnection costs up to the point of interconnection and the utility bear all costs at and after that point. (Sopogy Opening Brief at 6) DBEDT also advocates using the point of interconnection as the demarcation point for interconnection cost responsibility. (DBEDT Opening Brief at 84) In considering this issue, the Commission must be careful not to effectively subsidize developers by allowing developers to pass on their project specific costs to ratepayers. Because the developer receives 100% of the profits from the power sales, the developer should bear the total cost of interconnection to the electric grid to maintain the safety, reliability, and power quality of the electric grid. Having the developer pay the total cost associated with the project will allow for more economical projects to be installed over less economical projects. This is consistent with Rule 14H which requires larger distributed generation projects that have a higher negative impact to the electric grid to bear more of the cost regardless of the location of the point of interconnection. As one example, supervisory control cost is installed on the utility's side of the point of interconnection for communication and control to the utility's system operator to maintain the safety, reliability, and power quality of the electrical grid. Additionally, in order to maintain flexibility and reduce cost, developers may need to install certain shared equipment on the utility side of the point of interconnection such as a battery system to mitigate unstable power fluctuations. Moreover, as discussed above, without any financial risk or economic restraints due to system costs, a developer would be able to design its project without any consideration for the location and/or capacity of existing utility system facilities in the area, forcing the utilities to bear the costs of upgrading what could be miles of system facilities. This would be an unfair financial burden to the rest of the utilities' customers for the benefit of the developer. These concerns support the design of the Proposed FIT which seeks to establish pricing for a typical project rather than projects that are not efficiently designed.

Ultimately, the cost that the utility would have to bear should be taken into account for each of the projects being evaluated. Alternatively, to the extent the developer were to be transparent with regard to its costs it could demonstrate that the price of energy from the facility is reduced to offset the cost of the facilities paid for by the utility. Regardless, it must be shown that the overall cost of the project, including those costs born by the utility, is a good deal for the customers.

Sopogy also proposes that the Commission develop standard interconnection terms at both the distribution and transmission levels, including performance requirements for projects up to 20 MW in size. (Sopogy Opening Brief at 12) Fundamentally, standardized interconnection requirements for projects up to 20MW would be difficult to develop and may not be applicable to all projects even if the same renewable energy technology is used. Large projects should have separate studies done to understand what specifically is needed to accommodate that project. A study could actually save both the utility and the developer costs by ensuring that there is not an over or under investment in capital improvements.

More specifically, while certain minimum project requirements can be established, such as fault ride-through, and monitoring and control, there will always be requirements that are unique to the particular project due to its location on the system, availability of communications infrastructure, or particular requirements of the technology. Due to the unique issues created by the project's location on the power system, or for newer technology types, or for large generators that have significant individual impacts on the power system, a system impact and interconnection study would be required. This includes projects on the transmission system and projects that are in excess of the minimum threshold for study under rule 14H.

Q. Schedule Q Should Remain An Option For Those Resources For Which A FIT Is Not Yet Available.

The Joint Parties' Opening Brief proposed that: (1) "Once a FIT is available, no new applications for Schedule Q contracts should be accepted"; (2) "To the extent that a FIT option is not available for projects under 100 kW, Schedule Q would remain an option for those resources which qualify"; and (3) "Existing Schedule Q generators would have the option of opting in to the Proposed FIT or staying under their existing contractual arrangement through the term of their agreement."[31]

Sopogy appears to be in general agreement with this concept, as evidenced by Sopogy's contention that: "Existing Schedule Q contracts should have the option to migrate to a FIT, possibly for a reduced contract term depending on the number of years in service and expected life of the existing project." However, Sopogy goes on to maintain that: "Projects with technologies that do not qualify under FIT would use either non-bid PPAs or competitive bidding and Schedule Q would be phased out."[32] Sopogy's position in this regard goes a step too far.[33]

As Sopogy appears to recognize, there are legal considerations that would need to be addressed prior to Schedule Q being "phased out."[34] As explained in the Joint Responses to Legal Questions Regarding Feed-In Tariffs of the HECO Companies and Consumer Advocate

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31 See Joint Parties' Opening Brief at 12-13.
32 Sopogy Opening Brief at 7-8.
33 HREA Opening Brief at 1.

("Joint Responses"), the Commission's ability to substitute a FIT for Schedule Q as a means of complying with PURPA would depend on the scope of the FIT that is implemented, as the Commission's rules concerning Schedule Q: (1) only apply to QFs with design capacities of 100 kW or less; (2) do not provide for any limits on the amount of purchases from QFs; and (3) apply to a broad array of eligible technologies including "biomass, waste, renewable resources, solar, wind, geothermal, or any combination thereof".[35] Each of these characteristics of Schedule Q poses issues that would need to be addressed if Schedule Q were "phased out" by some combination of FITs, non-bid PPAs and competitive bidding.

With respect to the first point, the Commission's Framework for Competitive Bidding generally does not apply to generating units with a net output of 5 MW or less on Oahu (2.7 MW on Maui and the Big Island).[36] Accordingly, in order to serve as a substitute for Schedule Q, the Competitive Bidding Framework would need to be amended so as to apply to generation units with design capacities of less than one-fiftieth of the capacity floor currently applicable to the framework. In effect, the minimum capacity requirement of the Competitive Bidding Framework would be eliminated, resulting in a much larger number of projects being subjected to the framework.

With respect to the second point, to the extent FIT targets are approved and achieved, a determination would have to be made as to whether the FIT would be able to serve as a substitute for Schedule Q (for meeting a utility's PURPA obligation).

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34 See Sopogy Opening Brief at 8.

35 See Joint Responses at 38.

36 See Part II.A.3.f of the Commission's Framework for Competitive Bidding ("Competitive Bidding Framework"), attached as Exhibit A to Decision and Order No. 23121, filed December 8, 2006 in Docket No. 03-0372.

With respect to the third point, the Joint Parties' Opening Brief explained that, "The initial FIT should focus on the four technologies with which the HECO Companies have some commercial experience and which can more efficiently be accommodated through a FIT program: photovoltaic ("PV"), concentrated solar power ("CSP"), small wind, and in-line hydro facilities."[37] In other words, the initial FIT (as proposed) generally would not include other forms of renewable generation from resources currently covered under Schedule Q such as biomass, waste, geothermal, or combinations thereof.

If the FIT approved by the Commission does not apply to the foregoing types of generation resources, the FIT will not be able to serve as a substitute for procuring electricity from those types technologies. Under the Joint Parties' proposal, the renewable generators would be able to request a contract under Schedule Q. Under Sopogy's proposal, that option would not be available. That would mean that there may have to be additional negotiations on the terms of the contract (e.g., pricing).

R. Adjustments To The Competitive Bidding Framework, If Any, Should Occur Within The Context Of That Proceeding Or A Proceeding To Examine Those Issues – This Proceeding Should Not Be Allowed To Provide A Forum For Parties To Collaterally Attack The Framework.

On December 8, 2006, through Decision and Order No. 23121, the Commission adopted the Framework for Competitive Bidding ("Framework") as a mechanism for acquiring or building new energy generation in Hawaii. As noted in that Decision and Order, the Framework's underlying principle is that competitive bidding (unless exempted or waived by the Commission for a specific project) is established as the <u>required mechanism</u> for acquiring a future generation resource or a block of generation resources. (Decision and Order No. 23121 at

37 Joint Opening Brief at 5.

3) (emphasis supplied) The Joint Parties recommend that the Framework remain in place as competitive bidding is the best vehicle for discovering prices and to achieve the most economical pricing for ratepayers. This is especially critical for larger projects with their correspondingly larger ratepayer impacts.

Despite the Commission's clear identification of the competitive bidding process as the preferred vehicle for utility resource procurement, various intervenors believe the existing process is either flawed or should be modified. Sopogy proposes that the threshold for the Framework be raised to 20 MW and larger or for specific need.[38] (Sopogy Opening Brief at 8) Raising the competitive bidding threshold to 20 MW is not prudent for grids the size of Oahu's. System impacts at this size will not be able to be reasonably addressed through a standardized FIT process. Moreover, renewable energy projects under 20 MW proposed under the Framework are already triggering close examination of performance standards requirements. Additionally, setting the threshold too high limits the field of competition (small project developers cannot compete) and a higher threshold translates to less projects taken in. Projects that do not provide their fair contribution to performance standards will limit the amount of future renewable projects the system can take. Finally, 20MW is significantly larger than typical distribution circuit feeder loads and will result in power flow in the opposite direction in which these feeders were designed. Generators of this size may also exceed the thermal limits of distribution components.

DBEDT would go even further and proposes to consider increasing the minimum threshold for the Competitive Bidding Framework to 100 MW. (DBEDT Opening Brief at 38)

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[38] It appears that HREA is in favor of modifying the minimum threshold for the Framework to 50 MW. (HREA Opening Brief at 4)

However, raising the threshold is not necessary to incorporate more flexibility into competitive procurement process for smaller resources (<100 MW). Additionally, the draft RFP process (instead of Framework revisions) can propose more flexible approaches and present them for comments from bidders and the Commission's approval.

DBEDT also suggests that the Company should be required to file a procurement plan with the Commission under the competitive bidding process once every two or three years and justify its plan to purchase or not purchase resources (DBEDT Opening Brief at 37) DBEDT should be aware that Section II.A.2 of the Framework specifies that "[a] determination shall be made by the Commission in a utility's IRP proceeding as to whether a competitive bidding process shall be used to acquire a future generation resource or a block of generation resources." Additionally, the Company's ongoing CESP process will likely include competitive bidding plans proposed by the Company. Finally, DBEDT's recommendation that the Company should file the estimated costs of RFP projects would be counterproductive to the objectives of any competitive bidding process.

DBEDT also proposes that the Framework should be modified to include a timeline for each procedure in the Framework. It is important to note that the Framework already contains appropriate milestones to insure that the process is moving forward efficiently. Section IV.B.11 describes that the parties shall endeavor to complete the Final RFP within 90 days of issuance of the Draft RFP. Generally, a draft RFP is the more suitable vehicle for addressing RFP specific issues which may affect timelines since bidders and an Independent Observer may comment on the Draft RFP schedule, but do not generally have a procedural vehicle to comment on the Framework. The Commission can address timelines on an RFP specific basis weighing considerations such as the level of complexity, and specific procurement issues.

With regard to DBEDT's suggestion that the Company should file a report if no PPA is signed through the RFP process; pursuant to Section C.2.a.(iv) of the Framework, the Independent Observer must file a report at the end of the procurement process. Moreover, while not explicitly stated in the Framework, if the Company does not select any projects, an explanation would likely be expected to be provided to the Commission. Finally, with regard to DBEDT's assertion that the Framework should be modified to include a complaint process for bidders, Section V of the Framework already provides a dispute resolution process, and the RFP also includes a dispute resolution process.

S. The Term Of A FIT Agreement Should Be 20 Years With Any Extensions To Be Negotiated Between The Parties.

Through the Proposed FIT the Joint Parties stated that the term of FIT contracts for new resources should be no longer than industry-standard assumptions on service life for a particular technology. Pursuant to agreement reached during the March 18-19, 2009 technical conference and settlement discussions, the Parties agreed that the standard term for a Schedule FIT Agreement should be 20 years for all eligible renewable resources provided that appropriate evidence is presented to support this length of term as consistent with the average expected life of each eligible resource.

Following the initial term, projects should be allowed to extend their contracts on a year-by-year basis subject to a revised FIT energy rate appropriate for the specific project circumstance, considering among other factors the remaining useful life of the system (if any), the cost of generation to the developer (if any), and the FIT energy payment rates in effect at the time. The utility should not be obligated to purchase any energy if the FIT contract expires and is not renewed. (See KEMA Report, filed as a part of the Proposed FIT, page 33, Sec 3.9) This is generally consistent with the position taken by DBEDT in its Opening Brief, where it proposes that the contract may continue past term on a year to year basis unless terminated by 60 day notice by either party. Additionally, the FIT should specify any changes to the FIT rate that would apply (DBEDT Opening Brief at 67)

Sopogy supports an "up front" option for the renewable energy provider to continue to sell power to the utility upon expiration of the 20-year FIT term. Sopogy and HREA support a "one-time 5-year extension, or at the option of the FIT provider, the right to negotiate a new FIT or other power purchase alternatives that may be available at that time." (Sopogy Opening Brief at 11; HREA Opening Brief at 21) The option to extend the term at the sole option of the developer is unreasonable. Twenty years is already a significant long term commitment and certainly adequate for developers to finance their projects. Again, the Joint Parties have agreed to allow the project developer to recover its cost and a reasonable profit. The Commission should not approve what would in effect be a 25-year contract at the sole option of the developer and despite whether or not the utility had a need for that capacity and energy at the time of contract expiration. The Commission should also not adopt Sopogy's proposal to provide the developer with a "right" to negotiate a new FIT or "other power purchase alternative." At the termination of the 20-year contract term, the Commission should leave it to the parties to the contract to decide whether they choose to mutually enter into another contractual relationship at that time.[39]

T. The HECO Companies Appreciate Certain Of The Parties Recognition Of The Energy Agreement's Commitment To Keep The Utility Whole And To Facilitate The Continued Existence Of A Financially Viable Counter Party.

[39] SA/HSEA suggests that it "should be assumed that the generator will have only salvage value at the end of the 20 year term." (SA/HSEA Opening Brief at footnote 33). These types of issues should be reserved for consideration as a part of FIT rate development and should not be determined without appropriate stakeholder input.

As part of its recognition of the need for and commitment to a financially viable utility and contracting counterparty with renewable energy projects, the Energy Agreement expressly provides that utility PPAs for renewable energy under the Commission-approved feed-in tariff "shall be deemed to be prudent and their costs shall be approved for rate recovery." (Energy Agreement at 17)

Through their Opening Briefs, other parties have recognized the importance of assured cost recovery.[40] The HECO Companies appreciate this recognition and have the following comments regarding the parties' proposals. In particular, Sopogy supports utility recovery of FIT costs through the Energy Cost Adjustment Clause ("ECAC") as with current renewable PPAs. Sopogy would also support a cost recovery structure from either a special FIT Program Surcharge or from including FIT payments as part of the Clean Energy Infrastructure Surcharge." (Sopogy Opening Brief at 11) Additionally, DBEDT recommends that the Commission implement a separate Purchased Power Cost Recovery Adjustment (PPCRA) mechanism (separate from ECAC) that would allow the utilities to recover the costs of their renewable power purchases through FITs and through the other procurement mechanisms. (DBEDT Opening Brief at 76-77)

It is the HECO Companies position that given the Energy Agreement's commitment to cost recovery the most efficient and effective way to facilitate this cost recovery is through the well established and well vetted ECAC process for energy purchases. The ECAC is the process by which purchased energy payments are currently recovered and therefore it is appropriate that FIT purchased power energy costs should be recovered through the ECAC as well with FIT non-energy costs (e.g., capacity) recovered through a Purchased Power Adjustment Clause.

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[40] HREA Opening Brief at 22; HDA Opening Brief at 30

U. Repowered Existing Renewable Energy Generators And Capacity Additions To Existing Renewable Energy Generation Could Be Eligible For A FIT Contract Under Certain Circumstances.

Sopogy proposes that project expansions be eligible for a FIT. (Sopogy Opening Brief at 14) Additionally, through the Joint Parties' Opening Brief, it was clarified that an existing generator that is repowered (where a significant portion of the generating equipment is replaced) could be considered a "new" renewable energy generator and therefore could be eligible to receive the FIT. Similarly, capacity additions to existing renewable energy generation would require the entire capacity to be placed under a FIT. It must be recognized however that any discussion of project expansion must take into account the many detail challenges that exist, including how to address the cost of interconnection for an expanded facility which in part is paid via FIT, how to address that one part of the facility is under a PPA with one set of terms for a period of time and a part that may not be under a contract (and instead simply delivering as part of a tariff), with different commercial and operational terms. And although an expansion of a facility can happen more quickly than a new facility, if the original facility could be developed without a FIT, is it beneficial to ratepayers to allow an expansion to be eligible for a FIT rate designed for new facilities? Moreover, a capacity addition can be complicated because depending on the type of technology, for example an existing PV facility which adds modules, the new incremental addition may have a different cost structure due to a shared common infrastructure with the original equipment.

Because of these complications, all of which must be addressed and for which there is an insufficient record in this proceeding, the Commission should defer the issue of project expansions and repowerings as eligible for the FIT until the first FIT Update.

V. The Utility Should Have The Ability To Continue To Meet Its RPS Requirements Pursuant To Commission Oversight.

DBEDT proposes that utility development of renewable projects be allowed to occur only on a case by case basis with oversight of the processing of FIT applications by the Commission (DBEDT Opening Brief at 42-43). First, as discussed during the panel hearings, the utility will not be participating directly in the FIT as it is not "logically possible" for the utility to contract with itself (Panel Hearing Transcript at II-261, line 19 through approximately II-264, line 7). With regard to participation in the FIT by utility affiliates rather than the utility, the HECO Companies have committed not to directly participate in the initial FIT through any utility affiliates. However, given the HECO Companies' legal obligation to comply with the RPS, the HECO Companies reserve the right to develop or acquire utility-owned renewable resources outside of the FIT process to the extent that such development and/or acquisition is necessary to insure that RPS requirements, both existing and as modified in the future, may be met and the HECO Companies are able to satisfy their obligation under law. Such projects, if any, will be accomplished pursuant to the Commission's Rules of Practice and Procedure and General Orders governing utility ownership of resources and these regulatory processes will provide the necessary oversight and transparency to ensure that such procurement is undertaken consistent with the goals and policies of the Commission and State. In addition, utility-owned projects that provide opportunities to conduct research on mitigating impacts of variable generation may also be pursued, again, outside of the FIT. The Commission should reject DBEDT's proposal to use this proceeding to restrict the utility's legitimate, Commission reviewed procurement options outside of this proceeding.

W. The HECO Companies Anticipate Filing An Annual Report With The Commission On The Status Of The FIT Program And Identifying Issues To Be Considered In The Update Process.

DBEDT requests that the utility be required to submit an annual report on the Proposed FIT to the Commission. (DBEDT Opening Brief at 71-72) The Joint Parties believe it is appropriate to provide periodic reports to the Commission on the overall status of the FIT program, particularly as the parties and Commission prepare to participate in the regular FIT Update process. Therefore, the HECO Companies are not averse to providing the Commission with an annual report as directed by the Commission as a part of the Commission's approval of the Proposed FIT.

X. It Is Reasonable To Consider All Relevant Factors In The Design Of A Workable, Streamlined And Standardized Feed-In Tariff For Hawaii.

HECO and the Consumer Advocate agree that initially, the FIT should target those technologies that are actively being developed in Hawaii and on project types and sizes that are more straightforward to implement and lend themselves to use of standardized energy rates and power purchase contracting. Focusing on these resources will allow the Commission and stakeholders to more readily develop the Initial FIT. The Joint Parties stress that the FIT should be regularly reviewed to encompass more technologies, and propose to do so within two years of the Initial FIT, with ongoing reviews as part of the CESP process.

Thus, the proposed FIT initially targets renewable resources that (1) do not require complex environmental and land use permitting which may impose significant uncertainties in project development timeframes and costs; (2) do not inherently, by virtue of their operating characteristics and size relative to the utility system, require extensive and lengthy interconnection studies which may identify the need for significant interconnection requirements;

(3) do not trigger complex financial accounting issues relative to utility power purchase contracts; while these accounting issues will ultimately be resolved in the course of other Commission proceedings or processes, the timing of such may not support the desired timeframe to adopt an initial FIT; and (4) have already been, or are currently in the process of being, implemented in Hawaii in commercial (non-R&D) application.

DBEDT takes the position that the interconnection, permitting and accounting issues discussed as a part of the Proposed FIT should not be the basis for FIT eligibility. The issues discussed do not constitute eligibility requirements but rather were a part of the factors that were considered and evaluated as a part of designing a FIT which would be streamlined, standardized and efficient in the ability of a renewable energy resource to easily contract with the utility without the level of study, and negotiation with the utility that can be required as a part of a bilateral negotiation or certain other procurement mechanisms. Specifically, projects which require more complicated interconnection studies, more complex and time consuming permitting requirements, and more detailed accounting analysis to determine the financial implications of contracting with the particular resource were correctly determined to be factors to consider in designing a FIT.

III. CONCLUSION

The Proposed FIT is intended as an expedited and interim starting point for what will eventually become a simple, streamlined and broad tariff offering to as many renewable technologies as is feasible while also allowing for the effective, reliable and cost effective delivery of electrical service. For the reasons described herein, the Proposed FIT initially focuses on a subset of technologies and projects. The FIT will be regularly reviewed for the purpose of updating tariff pricing, applicable technologies, project sizes, and annual targets through the FIT Update. A FIT Update will be conducted for all islands in the HECO Companies' service territory not later than two years after initial implementation of the FIT. Thereafter, the FIT Update will be conducted every three years, incorporating inputs from the CESP process.

As discussed above, the issues to be addressed and decisions to be rendered in this docket are presented not in a vacuum, but in the context of the State's energy infrastructure and policy both as they exist today and as they are envisioned to change in the future. The Proposed FIT appropriately balances incentives to build with the need to maintain system security, power quality and avoid adverse ratepayer impacts. The Proposed FIT complements a host of other renewable resource procurement programs in existence and to be developed by the HECO Companies to facilitate movement toward a renewable energy future for the State. The HECO Companies and Consumer Advocate respectfully submit that the Proposed FIT is the only proposal which is supported by the record, which appropriately considers all of the variables for determination by the Commission in context, and which provides a going forward solution which is both innovative and responsible.

To the extent that the Commission requires any further or supplemental information in response to the assertions or allegations raised by the intervenors through their Opening Briefs, the HECO Companies and Consumer Advocate are prepared to respond to any further inquiries from the Commission.

Dated: Honolulu, Hawaii, June 26, 2009.

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CERTIFICATE OF SERVICE

The foregoing Reply Brief of the HECO Companies and Consumer Advocate was served on the date of filing by mail, postage prepaid, and properly addressed or electronically transmitted to each such Party.

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